

and either recycling the H₂S to the reactor furnace or the first-stage catalytic reactor of the Claus sulfur recovery plant or converting the H₂S to a sulfur product.

Refinery process unit means any segment of the petroleum refinery in which a specific processing operation is conducted.

Sulfur pit means the storage vessel in which sulfur that is condensed after each Claus catalytic reactor is initially accumulated and stored. A *sulfur pit* does not include secondary sulfur storage vessels downstream of the initial Claus reactor sulfur pits.

Sulfur recovery plant means all process units which recover sulfur from HS₂ and/or SO₂ at a petroleum refinery. The *sulfur recovery plant* also includes sulfur pits used to store the recovered sulfur product, but it does not include secondary sulfur storage vessels downstream of the sulfur pits. For example, a Claus sulfur recovery plant includes: Reactor furnace and waste heat boiler, catalytic reactors, sulfur pits, and, if present, oxidation or reduction control systems, or incinerator, thermal oxidizer, or similar combustion device. Multiple sulfur recovery units are a single affected facility only when the units share the same source of sour gas. Sulfur recovery plants that receive sour gas from completely segregated sour gas treatment systems are separate affected facilities.

§ 60.102a Emissions limitations.

(a) Each owner or operator that is subject to the requirements of this subpart shall comply with the emissions limitations in paragraphs (b) through (h) of this section on and after the date on which the initial performance test, required by § 60.8, is completed, but not later than 60 days after achieving the maximum production rate at which the affected facility will be operated, or 180 days after initial startup, whichever comes first.

(b) An owner or operator subject to the provisions of this subpart shall not discharge or cause the discharge into the atmosphere from any FCCU or FCU:

(1) Particulate matter (PM) in excess of the limits in paragraphs (b)(1)(i), (ii), or (iii) of this section.

(i) 1.0 kilogram per Megagram (kg/Mg) (1 pound (lb) per 1,000 lb) coke burn-off or, if a PM continuous emission monitoring system (CEMS) is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each modified or reconstructed FCCU.

(ii) 0.5 gram per kilogram (g/kg) coke burn-off (0.5 lb PM/1,000 lb coke burn-off) or, if a PM CEMS is used, 0.020 gr/dscf corrected to 0 percent excess air for each newly constructed FCCU.

(iii) 1.0 kg/Mg (1 lb/1,000 lb) coke burn-off; or if a PM CEMS is used, 0.040 grain per dry standard cubic feet (gr/dscf) corrected to 0 percent excess air for each affected FCU.

(2) Nitrogen oxides (NO_x) in excess of 80 parts per million by volume (ppmv), dry basis corrected to 0 percent excess air, on a 7-day rolling average basis.

(3) Sulfur dioxide (SO₂) in excess of 50 ppmv dry basis corrected to 0 percent excess air, on a 7-day rolling average basis and 25 ppmv, dry basis corrected to 0 percent excess air, on a 365-day rolling average basis.

(4) Carbon monoxide (CO) in excess of 500 ppmv, dry basis corrected to 0 percent excess air, on an hourly average basis.

(c) The owner or operator of a FCCU or FCU that uses a continuous parameter monitoring system (CPMS) according to § 60.105a(b)(1) shall comply with the applicable control device parameter operating limit in paragraph (c)(1) or (2) of this section.

(1) If the FCCU or FCU is controlled using an electrostatic precipitator:

(i) The 3-hour rolling average total power and secondary current to the entire system must not fall below the level established during the most recent performance test; and

(ii) The daily average exhaust coke burn-off rate must not exceed the level established during the most recent performance test.

(2) If the FCCU or FCU is controlled using a wet scrubber:

(i) The 3-hour rolling average pressure drop must not fall below the level established during the most recent performance test; and

(ii) The 3-hour rolling average liquid-to-gas ratio must not fall below the

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level established during the most recent performance test.

(d) If an FCCU or FCU uses a continuous opacity monitoring system (COMS) according to the alternative monitoring option in § 60.105a(e), the 3-hour rolling average opacity of emissions from the FCCU or FCU as measured by the COMS must not exceed the site-specific opacity limit established during the most recent performance test.

(e) The owner or operator of a FCCU or FCU that is exempted from the requirement for a CO continuous emissions monitoring system under § 60.105a(h)(3) shall comply with the parameter operating limits in paragraph (e)(1) or (2) of this section.

(1) For a FCCU or FCU with no post-combustion control device:

(i) The hourly average temperature of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(ii) The hourly average oxygen (O₂) concentration of the exhaust gases exiting the FCCU or FCU must not fall below the level established during the most recent performance test.

(2) For a FCCU or FCU with a post-combustion control device:

(i) The hourly average temperature of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(ii) The hourly average O₂ concentration of the exhaust gas vent stream exiting the control device must not fall below the level established during the most recent performance test.

(f) Except as provided in paragraph (f)(3), each owner or operator of an affected sulfur recovery plant shall comply with the applicable emission limits in paragraphs (f)(1) or (2) of this section.

(1) For a sulfur recovery plant with a capacity greater than 20 long tons per day (LTD):

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 250 ppm by volume (dry basis) of sulfur dioxide (SO₂) at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 250 ppmv limit for each process train or release point or comply with a flow rate weighted average of 250 ppmv for all release points from the sulfur recovery plant; or

(ii) For sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 300 ppm by volume of reduced sulfur compounds and 10 ppm by volume of hydrogen sulfide (HS₂), each calculated as ppm SO₂ by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 1 of this section:

$$E_{LS} = k_1 \times (-0.038 * (\% O_2)^2 + 11.53 * \% O_2 + 25.6) \quad (\text{Eq. 1})$$

Where:

E_{LS} = Emission rate of SO₂ for large sulfur recovery plant, ppmv;

k_1 = Constant factor for emission limit conversion: $k_1 = 1$ for converting to SO₂ limit and $k_1 = 1.2$ for converting to the reduced sulfur compounds limit; and

$\%O_2$ = O₂ concentration to the SRP, percent by volume (dry basis).

(2) For a sulfur recovery plant with a capacity of 20 LTD or less:

(i) For a sulfur recovery plant with an oxidation control system or a reduction control system followed by incineration, the owner or operator shall not discharge or cause the discharge of any gases into the atmosphere in excess of 2,500 ppm by volume (dry basis)

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of SO₂ at zero percent excess air. If the sulfur recovery plant consists of multiple process trains or release points the owner or operator shall comply with the 2,500 ppmv limit for each process train or release point or comply with a flow rate weighted average of 2,500 ppmv for all release points from the sulfur recovery plant; or

(ii) For sulfur recovery plant with a reduction control system not followed by incineration, the owner or operator

shall not discharge or cause the discharge of any gases into the atmosphere in excess of 3,000 ppm by volume of reduced sulfur compounds and 100 ppm by volume of hydrogen sulfide (H₂S), each calculated as ppm SO₂ by volume (dry basis) at zero percent excess air; or

(iii) For systems using oxygen enrichment, the owner or operator shall calculate the applicable emission limit using Equation 2 of this section:

$$E_{ss} = k_1 \times (-0.38 * (\% O_2)^2 + 115.3 * \% O_2 + 256) \quad (\text{Eq. 2})$$

Where:

E_{ss} = Emission rate of SO₂ for small sulfur recovery plant, ppmv.

(3) Periods of maintenance of the sulfur pit, during which the emission limits in paragraphs (f)(1) and (2) shall not apply, shall not exceed 240 hours per year. The owner or operator must document the time periods during which the sulfur pit vents were not controlled and measures taken to minimize emissions during these periods. Examples of these measures include not adding fresh sulfur or shutting off vent fans.

(g) Each owner or operator of an affected fuel gas combustion device shall comply with the emission limits in paragraphs (g)(1) through (3) of this section.

(1) For each fuel gas combustion device, the owner or operator shall comply with either the emission limit in paragraph (g)(1)(i) of this section or the fuel gas concentration limit in paragraph (g)(1)(ii) of this section.

(i) The owner or operator shall not discharge or cause the discharge of any gases into the atmosphere that contain SO₂ in excess of 20 ppmv (dry basis, corrected to 0 percent excess air) determined hourly on a 3-hour rolling average basis and SO₂ in excess of 8 ppmv (dry basis, corrected to 0 percent excess air), determined daily on a 365 successive day rolling average basis; or

(ii) The owner or operator shall not burn in any fuel gas combustion device any fuel gas that contains H₂S in excess of 162 ppmv determined hourly on a 3-hour rolling average basis and H₂S

in excess of 60 ppmv determined daily on a 365 successive calendar day rolling average basis.

(2) For each process heater with a rated capacity of greater than 40 million British thermal units per hour (MMBtu/hr), the owner or operator shall not discharge to the atmosphere any emissions of NO_x in excess of 40 ppmv (dry basis, corrected to 0 percent excess air) on a 24-hour rolling average basis.

(3) Except as provided in paragraphs (h) and (i) of this section, the owner or operator of an affected flare shall not allow flow to each affected flare during normal operations of more than 7,080 standard cubic meters per day (m³/day) (250,000 standard cubic feet per day (scfd)) on a 30-day rolling average. The owner or operator of a newly constructed or reconstructed flare shall comply with the emission limit in this paragraph by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare shall comply with the emission limit in this paragraph by no later than 1 year after that flare becomes an affected flare subject to this subpart.

(h) The combustion in a flare of process upset gases or fuel gas that is released to the flare as a result of relief valve leakage or other emergency malfunctions is exempt from paragraph (g) of this section.

(i) In periods of fuel gas imbalance that are described in the flare management plan required in section

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60.103a(a), compliance with the emission limit in paragraph (g)(3) of this section is demonstrated by following the procedures and maintaining records described in the flare management plan to document the periods of excess fuel gas.

§ 60.103a Work practice standards.

(a) Each owner or operator that operates a flare that is subject to this subpart shall develop and implement a written flare management plan. The owner or operator of a newly constructed or reconstructed flare must develop and implement the flare management plan by no later than the date that flare becomes an affected flare subject to this subpart. The owner or operator of a modified flare must develop and implement the flare management plan by no later than 1 year after the flare becomes an affected flare subject to this subpart. The plan must include:

(1) A diagram illustrating all connections to the flare;

(2) Methods for monitoring flow rate to the flare, including a detailed description of the manufacturer's specifications, including but not limited to, make, model, type, range, precision, accuracy, calibration, maintenance, and quality assurance procedures for flare gas monitoring devices;

(3) Procedures to minimize discharges to the flare gas system during the planned start-up and shutdown of the refinery process units that are connected to the affected flare;

(4) Procedures to conduct a root cause analysis of any process upset or malfunction that causes a discharge to the flare in excess of 14,160 m³/day (500,000 scfd);

(5) Procedures to reduce flaring in cases of fuel gas imbalance (i.e., excess fuel gas for the refinery's energy needs); and

(6) Explanation of procedures to follow during times that the flare must exceed the limit in § 60.102a(g)(3) (e.g., keep records of natural gas purchases to support assertion that the refinery is producing more fuel gas than needed to operate the processes).

(b) Each owner or operator that operates a fuel gas combustion device or sulfur recovery plant subject to this

subpart shall conduct a root cause analysis of any emission limit exceedance or process start-up, shutdown, upset, or malfunction that causes a discharge to the atmosphere in excess of 227 kilograms per day (kg/day) (500 lb per day (lb/day)) of SO₂. For any root cause analysis performed, the owner or operator shall record the identification of the affected facility, the date and duration of the discharge, the results of the root cause analysis, and the action taken as a result of the root cause analysis. The first root cause analysis for a modified flare must be conducted no later than the first discharge that occurs after the flare has been an affected flare subject to this subpart for 1 year.

(c) Each owner or operator of a delayed coking unit shall depressure to 5 lb per square inch gauge (psig) during reactor vessel depressuring and vent the exhaust gases to the fuel gas system for combustion in a fuel gas combustion device.

§ 60.104a Performance tests.

(a) The owner or operator shall conduct a performance test for each FCCU, FCU, sulfur recovery plant, and fuel gas combustion device to demonstrate initial compliance with each applicable emissions limit in § 60.102a according to the requirements of § 60.8. The notification requirements of § 60.8(d) apply to the initial performance test and to subsequent performance tests required by paragraph (b) of this section (or as required by the Administrator), but does not apply to performance tests conducted for the purpose of obtaining supplemental data because of continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(b) The owner or operator of a FCCU or FCU that elects to monitor control device operating parameters according to the requirements in § 60.105a(b), to use bag leak detectors according to the requirements in § 60.105a(c), or to use COMS according to the requirements in § 60.105a(e) shall conduct a PM performance test at least once every 12 months and furnish the Administrator a written report of the results of each test.